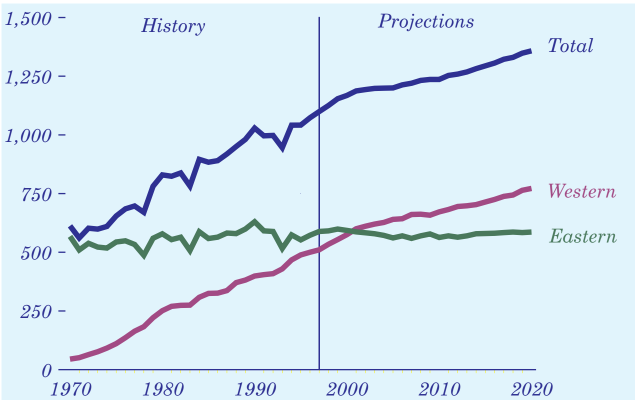
Continued Growth Is Projected for Coal Production from Western Mines

Figure 107. Coal production by region, 1970-2020 (million short tons)



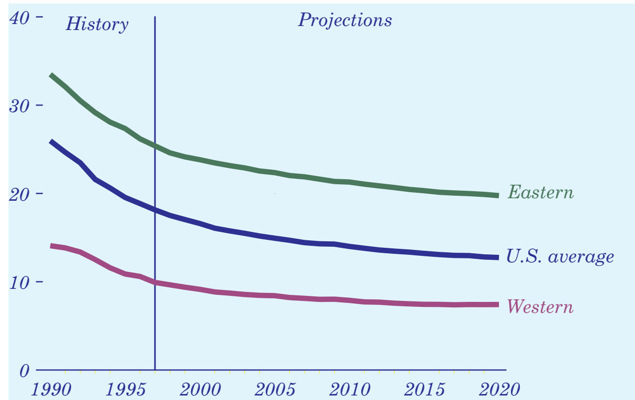
Continued improvements in mine productivity (averaging 6.2 percent a year since 1977) are projected to cause falling real mine prices throughout the forecast. Higher electricity demand and lower prices, in turn, yield increasing coal demand, but the demand is subject to a fixed sulfur emissions cap from CAAA90, which mandates progressively greater reliance on the lowest sulfur coals (from Wyoming, Montana, Colorado, and Utah).

The use of western coals can result in up to 85 percent less sulfur emissions than the use of many types of higher sulfur eastern coal. As coal demand grows, however, new coal-fired generating capacity is required to use the best available control technology: scrubbers or advanced coal technologies that can reduce sulfur emissions by 90 percent or more. Thus, even as the demand for low-sulfur coal grows, there will still be a market for low-cost higher-sulfur coal throughout the forecast.

From 1997 to 2020, high- and medium-sulfur coal production rises from 654 to 662 million tons (0.1 percent a year), and low-sulfur coal production rises from 445 to 696 million tons (2.0 percent a year). As a result of the competition between low-sulfur coal and post-combustion sulfur removal, western coal production continues its historic growth, reaching 772 million tons in 2020 (Figure 107), but its annual growth rate falls from the 9.4 percent achieved between 1970 and 1997 to 1.8 percent in the forecast period.

Further Declines Are Seen for U.S. Minemouth Coal Prices

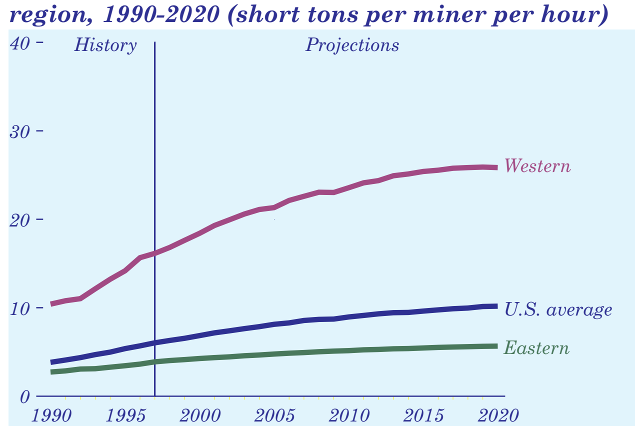
Figure 108. Average minemouth price of coal by region, 1990-2020 (1997 dollars per ton)



Minemouth coal prices declined by $4.97 per ton in 1997 dollars between 1970 and 1997, and they are projected to decline by 1.5 percent a year, or $5.40 per ton, between 1997 and 2020 (Figure 108). The price of coal delivered to electricity generators, which was essentially unchanged between 1970 and 1997, falls to $18.77 per ton in 2020—a 1.4-percent annual decline.

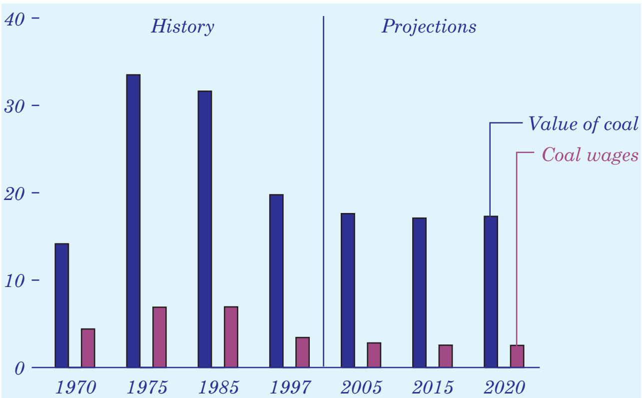
The mines of the Northern Great Plains, with thick seams and low overburden ratios, have had higher labor productivity than other coalfields, and their advantage is maintained throughout the forecast. Average U.S. labor productivity (Figure 109) follows the trend for eastern mines most closely, because eastern mining is more labor-intensive than western mining.

Figure 109. Coal mining labor productivity by region, 1990-2020 (short tons per miner per hour)



Additional Declines in Mine Labor Costs Are Projected

Figure 110. Labor cost component of minemouth coal prices, 1970-2020 (billion 1997 dollars)



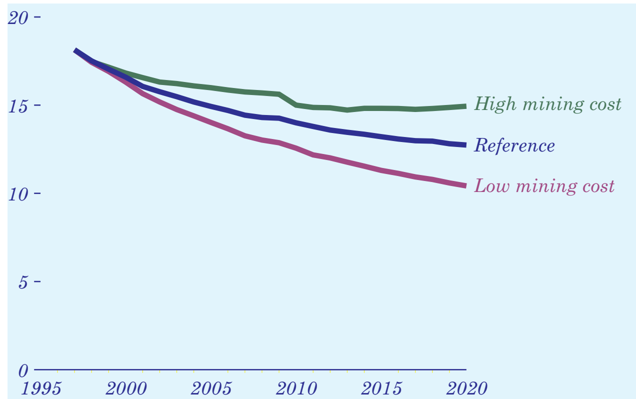
Gains in coal mine labor productivity result from technology improvements, economies of scale, and better mine design. At the national level, however, average labor productivity will also be influenced by changing regional production shares. Competition from very low sulfur, low-cost western and imported coals is projected to limit the growth of eastern low-sulfur coal mining. Western low-sulfur coal has been successfully tested in all U.S. Census divisions except New England and the Mid-Atlantic, and its penetration of eastern markets is projected to increase.

Eastern coalfields contain extensive reserves of higher sulfur coal in moderately thick seams suited to longwall mining. Maturing technologies for extracting and hauling high coal volumes in both surface and underground mining suggest that further reductions in mining cost are likely. Improvements in labor productivity have been, and are expected to remain, the key to lower coal mining costs.

As labor productivity improved between 1970 and 1997, the number of miners fell by 2.1 percent a year. With improvements continuing through 2020, a further decline of 1.3 percent a year in the number of miners is projected. The share of wages in minemouth coal prices [*70*], which fell from 31 percent to 17 percent between 1970 and 1997, is projected to decline to 15 percent by 2020 (Figure 110).

Even With Higher Cost Assumptions, Coal Prices Are Projected To Fall

Figure 111. Average minemouth coal prices in three cases, 1997-2020 (1997 dollars per ton)

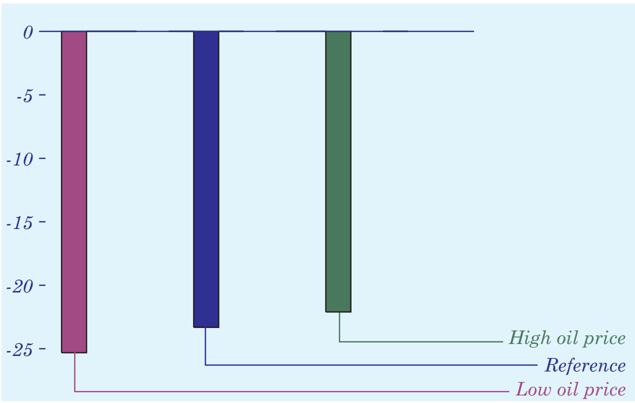


Alternative assumptions about future regional mining costs affect the market shares of eastern and western mines and the national average minemouth price of coal. In two alternative mining cost cases, demand for coal by electricity generators was allowed to respond to relative fuel prices, but coal demand from other sectors was held constant. Minemouth prices, delivered prices, and resultant regional coal production levels varied with changes in mining costs.

In the reference case projections, productivity increases by 2.3 percent a year through 2020, while wage rates are constant in 1997 dollars. The national minemouth coal price declines by 1.5 percent a year to $12.74 per ton in 2020 (Figure 111). In the low mining cost case, productivity increases by 3.8 percent a year, and real wages decline by 0.5 percent a year [*71*]. The average minemouth price falls by 2.4 percent a year to $10.42 per ton in 2020 (18.2 percent less than in the reference case). Eastern coal production is 17 million tons higher in the low case than in the reference case in 2020, reflecting the higher labor intensity of mining in eastern coalfields. In the high mining cost case, productivity increases by only 1.2 percent a year, and real wages increase by 0.5 percent a year. The average minemouth price of coal falls by 0.8 percent a year to $14.94 per ton in 2020 (17.3 percent higher than in the reference case). Eastern production in 2020 is 52 million tons lower in the high labor cost case than in the reference case.

Lower Coal Transportation Costs Are Projected Through 2020

Figure 112. Percent change in coal transportation costs in three cases, 1997-2020

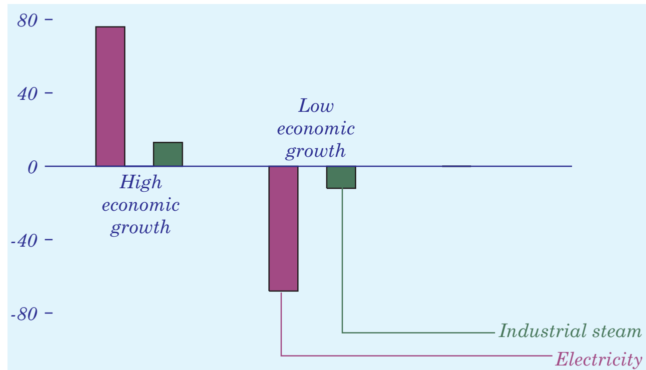


The competition between coal and other fuels, and among coalfields, is influenced by coal transportation costs. Changes in fuel costs affect transportation rates (Figure 112), but fuel efficiency also grows with other productivity improvements in the forecast. As a result, in the reference case, average coal transportation rates decline by 1.1 percent a year between 1997 and 2020. The most rapid declines have occurred on routes that originate in coalfields with the greatest declines in real minemouth prices. Railroads are likely to reinvest profits from increasing coal traffic to reduce transportation costs and, thus, expand the market for such coal. Therefore, coalfields that are most successful at improving productivity and lowering minemouth prices are likely to obtain the lowest transportation rates and, consequently, the largest markets at competitive delivered prices.

Expansion of the national market for Powder River Basin coal slowed during 1996 and 1997 as a result of rail service problems after the Union Pacific-Southern Pacific railroad merger. Many Gulf Coast and Midwest consumers had problems maintaining coal stocks as the frequency and predictability of unit-train coal deliveries deteriorated. Improvements in the first two quarters of 1998 suggest that service efficiency is returning to pre-merger levels. Activities resulting from other mergers, such as the current integration of Conrail within Norfolk Southern and CSX, may cause similar short-term problems, but *AEO99* projects that rail rates for coal will continue their historic decline in real terms.

Slower Economic Growth Could Reduce Demand for Coal

Figure 113. Variation from reference case projection of coal demand in two alternative cases, 2020 (million short tons)

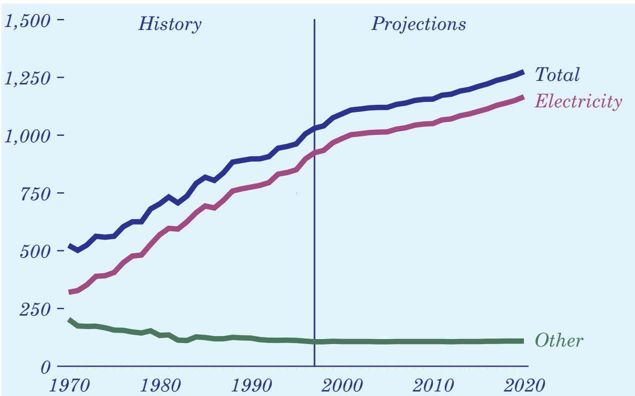


A strong correlation between economic growth and electricity use accounts for the variation in coal demand across the economic growth cases (Figure 113), with domestic coal consumption ranging from 1,195 to 1,363 million tons. Of the difference, coal use for electricity generation makes up 144 million tons. The difference in total coal production between the two economic growth cases is 166 million tons, of which 94 million tons (57 percent) is projected to be western production. Despite the fact that western coal must travel up to 2,000 miles to reach some of its markets, when its transportation costs are added to its low mine price and low sulfur allowance cost, it remains competitively priced in all regions except the Northeast.

Changes in world oil prices affect the costs of energy (both diesel fuel and electricity) for coal mining. In the high and low oil price cases, average minemouth coal prices are 0.2 percent higher and 0.6 percent lower, respectively, in 2020 than in the reference case. The low world oil price case projects 33 million tons less coal use in 2020 than in the high world oil price case as low oil prices encourage electricity generation from oil, while high oil prices encourage greater coal consumption. About 55 percent of the difference in production levels is western coal needed to meet the sulfur emissions cap. The higher coal consumption in the high oil price case is shared between the electricity generation and industrial steam coal sectors, with electricity taking 28 million tons (85 percent) of the difference and the industrial sector gaining the rest.

Electricity Generation Sets the Trend for U.S. Coal Consumption

Figure 114. Electricity and other coal consumption, 1970-2020 (million short tons per year)



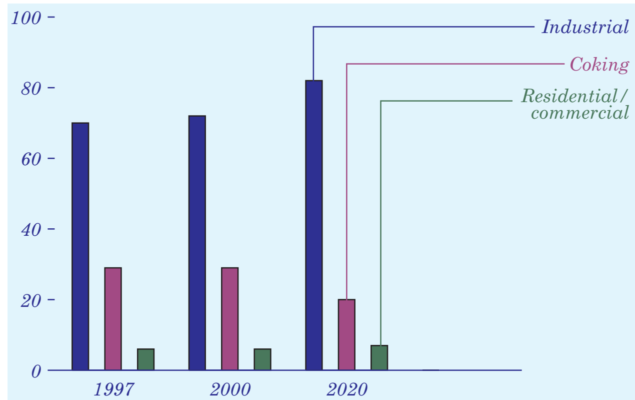
Domestic coal demand rises by 245 million tons in the forecast, from 1,030 million tons in 1997 to 1,275 million tons in 2020 (Figure 114), because of growth in coal use for electricity generation. Coal demand in other domestic end-use sectors increases by 3 million tons, as reduced coking coal consumption is offset by coal demand for industrial cogeneration.

Coal consumption for electricity generation (excluding industrial cogeneration) rises from 924 million tons in 1997 to 1,166 million tons in 2020, due to increased utilization of existing generation capacity and, in later years, additions of new capacity. The average utilization rate for coal-fired power plants increases from 67 to 79 percent between 1997 and 2020. Coal consumption (in tons) per kilowatthour of generation is higher for subbituminous and lignite coals than for bituminous coal. Thus, the shift to western coal increases the tonnage per kilowatthour of generation in midwestern and southeastern regions. In the East, generators shift from higher to lower sulfur Appalachian bituminous coals that contain more energy (Btu) per short ton.

Although coal maintains its fuel cost advantage over both oil and natural gas, gas-fired generation is the most economical choice for construction of new power generation units through 2010 when capital, operating, and fuel costs are considered. Between 2010 and 2020, rising natural gas costs and nuclear retirements are projected to cause increasing demand for coal-fired baseload capacity.

Industrial Coal Use Is Projected To Increase

Figure 115. Non-electricity coal consumption by sector, 1997, 2000, and 2020 (million short tons)



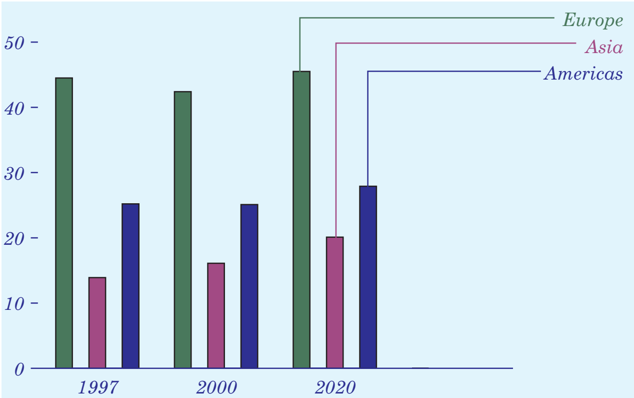
In the non-electricity sectors, an increase of 12 million tons in industrial steam coal consumption between 1997 and 2020 (0.7-percent annual growth) is offset by a decrease of 9 million tons in coking coal consumption (Figure 115). Increasing consumption of industrial steam coal results primarily from increased use of coal in the chemical and food-processing industries and from increased use of coal for cogeneration (the production of both electricity and usable heat for industrial processes).

The projected decline in domestic consumption of coking coal results from the displacement of raw steel production from integrated steel mills (which use coal coke for energy and as a material input) by increased production from minimills (which use electric arc furnaces that require no coal coke) and by increased imports of semi-finished steels. The amount of coke required per ton of pig iron produced is also declining, as process efficiency improves and injection of pulverized steam coal is used increasingly in blast furnaces. Domestic consumption of coking coal is projected to fall by 1.7 percent a year through 2020. Domestic production of coking coal is stabilized, in part, by sustained levels of export demand.

While total energy consumption in the residential and commercial sectors grows by 0.8 percent a year, most of the growth is captured by electricity and natural gas. Coal consumption in these sectors remains constant, accounting for less than 1 percent of total U.S. coal demand.

U.S. Coal Exports Rise Slowly in the *AEO99* Projections

Figure 116. U.S. coal exports by destination, 1997, 2000, and 2020 (million short tons)



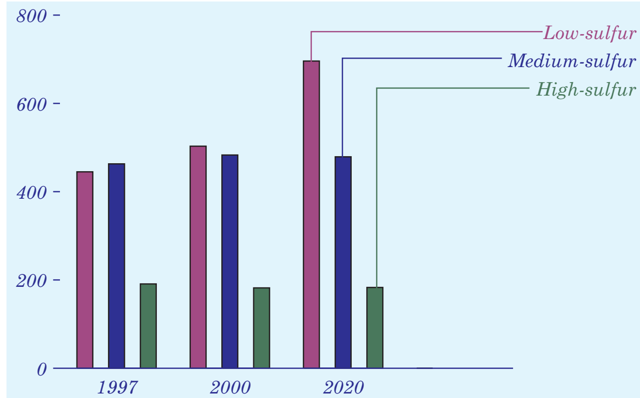
U.S. coal exports rise slowly in the forecast, from 84 million tons in 1997 to 93 million in 2020 (Figure 116), primarily as a result of higher demand for steam coal imports in Asia. Exports of metallurgical coal in 2020 are slightly lower than the 1997 level. Worldwide trade in metallurgical coal declines slightly, reflecting generally slow growth in steel production and improved process efficiency, but the U.S. market share remains essentially unchanged.

U.S. steam coal exports to Europe increase from 13 million tons in 1997 to 20 million in 2020 (1.9-percent annual growth). Europe's steam coal imports rise from 119 million tons in 1997 to 135 million tons in 2020 (0.5 percent a year), reflecting reduced subsidies for domestic coal production, as well as some new generating capacity. The *AEO99* forecast for European imports is lower than some that have been provided by the governments of the importing nations themselves, where environmental considerations, including emerging carbon emissions issues, limit fuel choices.

U.S. coal exports to Asia increase by 1.6 percent a year, from 14 million tons in 1997 to 20 million in 2020, as metallurgical exports fall by 1.5 percent and steam coal exports rise by 3.8 percent annually. Coal imports to Asia from all sources rise by 1.6 percent a year, from 274 million tons in 1997 to 394 million in 2020, as Pacific Rim nations without indigenous fossil fuel resources base electricity generation on imported coal. Most of the growth in Asian imports is projected to be supplied by Australia, South Africa, China, and Indonesia.

Low-Sulfur Coal Is Expected To Gain Market Share

Figure 117. Coal distribution by sulfur content, 1997, 2000, and 2020 (million short tons)



Phase 1 of CAAA90 required 261 coal-fired generators to reduce sulfur dioxide emissions to about 2.5 pounds per million Btu of fuel. Phase 2, which begins in 2000, tightens the annual emissions limits imposed on these large, higher-emitting plants and also sets restrictions on smaller, cleaner plants fired by coal, oil, and gas. The program affects existing utility units serving generators over 25 megawatts capacity and all new utility units [*72*].

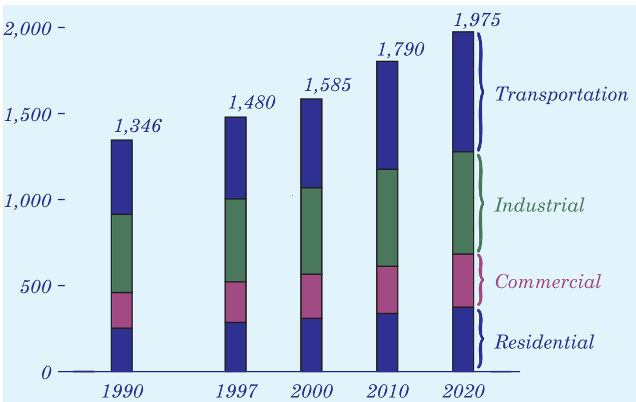
Relatively modest capital investments have allowed many generators to blend very low sulfur subbituminous and bituminous coal in Phase 1 affected boilers. Such fuel switching often generates sulfur dioxide allowances beyond those needed for Phase 1 compliance. Excess allowances are banked for use in Phase 2 or sold to other generators (the proceeds of such sales can be seen as further reducing fuel costs for the seller). Fuel switching for regulatory compliance and cost savings is projected to reduce the composite sulfur content of all coal produced (Figure 117). National sulfur emissions from coal-fired generators have already declined by approximately 24 percent between 1990 and 1995 [*73*].

Coal users may incur additional costs in the future if environmental problems associated with nitrogen oxides, particulate emissions, and possibly CO_2 emissions from coal combustion are monetized and added to the costs of coal combustion. The most probable method would be a regulatory market mechanism like that established under CAAA90 to price sulfur emissions.

Carbon Emissions and Energy Use

Without New Policies, Carbon Emissions Are Projected To Grow

Figure 118. Carbon emissions by sector, 1990-2020 (million metric tons per year)



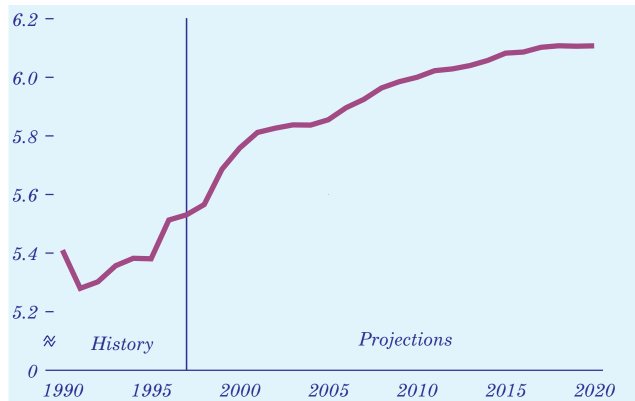
Carbon emissions from energy use are projected to increase by an average of 1.3 percent a year from 1997 to 2020, reaching 1,975 million metric tons (Figure 118). This projection is slightly higher than the *AEO98* projection of 1,956 million metric tons, due to higher energy consumption—particularly, coal for electricity generation and petroleum for transportation.

Increasing concentrations of carbon dioxide, methane, nitrous oxide, and other greenhouse gases may increase the Earth's temperature and affect the climate. The *AEO99* projections include analysis of the Climate Change Action Plan (CCAP), developed by the Clinton Administration in 1993 to stabilize U.S. greenhouse gas emissions by 2000 at 1990 levels. Carbon emissions from fuel combustion, the primary source of greenhouse gas emissions, were about 1,346 million metric tons in 1990. The analysis does not account for carbon-absorbing sinks, the 13 CCAP actions related to non-energy programs or gases other than carbon dioxide, nor any future mitigation actions that may be considered to meet the reductions proposed in the Kyoto Protocol.

Emissions in the 1990s have grown more rapidly than projected at the time CCAP was formulated, partly due to lower energy prices and higher economic growth than projected, which have led to higher energy demand. In addition, some CCAP programs have been curtailed. Additional carbon mitigation programs, technology improvements, or more rapid adoption of voluntary programs could result in lower emissions levels than projected here.

Increasing Use of Electricity Raises Per Capita Carbon Emissions

Figure 119. Carbon emissions per capita, 1990-2020 (metric tons per person)



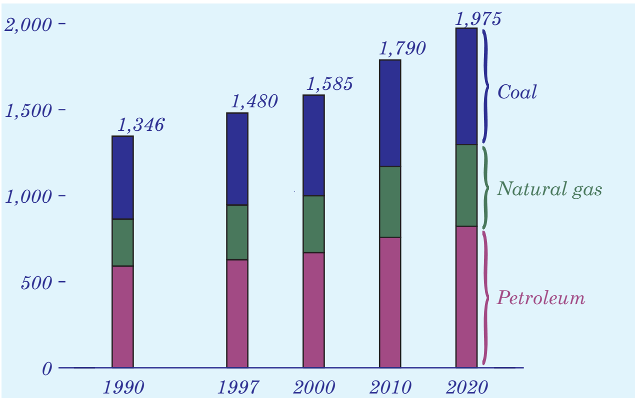
U.S. carbon emissions from energy use are projected to grow at an average annual rate of 1.3 percent; however, per capita emissions grow by only 0.4 percent a year (Figure 119). To stabilize or reduce total emissions, population growth would need to be offset by reductions in per capita emissions.

Emissions in the residential sector, including emissions from the generation of electricity used in the sector, are projected to increase by 1.2 percent a year, reflecting the ongoing trends of electrification and penetration of new appliances and services. Significant growth in office equipment and other uses is also projected in the commercial sector, but growth in consumption—and in emissions, which also increase by 1.2 percent a year—is likely to be moderated by slowing growth in floorspace, coupled with efficiency standards, voluntary efficiency programs, and technology improvements.

Transportation emissions grow at an average annual rate of 1.7 percent as a result of increases in vehicle-miles traveled and freight and air travel, combined with slow growth in the average light-duty fleet efficiency. Industrial emissions are projected to grow by only 0.9 percent a year, as shifts to less energy-intensive industries and efficiency gains moderate growth in energy use.

Petroleum Products Lead Growth in Carbon Emissions From Energy Use

Figure 120. Carbon emissions by fuel, 1990-2020 (million metric tons per year)



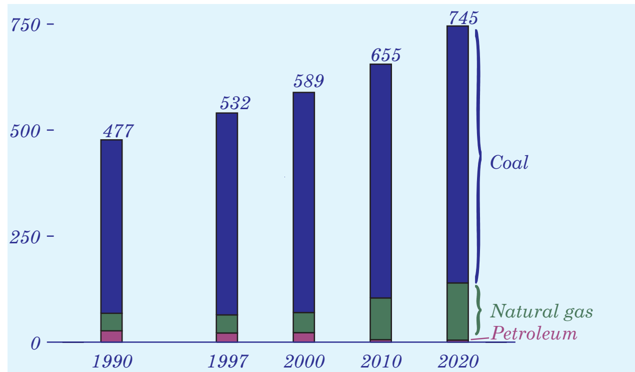
Petroleum products are the leading source of carbon emissions from energy use. In 2020, petroleum is projected to contribute 823 million metric tons of carbon to the total 1,975 million tons, a 42-percent share (Figure 120). About 81 percent (665 million metric tons) of the petroleum emissions result from transportation use, which could be lower with less travel or more rapid development and adoption of higher efficiency or alternative-fuel vehicles.

Coal is the second leading source of carbon emissions, projected to produce 676 million metric tons in 2020, or 34 percent of the total. The share declines from 36 percent in 1997 because coal consumption increases at a slower rate through 2020 than consumption of petroleum and natural gas, the sources of virtually all other energy-related carbon emissions. Most of the increases in coal emissions result from electricity generation. A slight increase in emissions from industrial steam coal use is partially offset by a decline in emissions from coking coal.

In 2020, natural gas use is projected to produce 475 million metric tons of carbon emissions, a 24-percent share. Of the fossil fuels, natural gas consumption and emissions increase most rapidly through 2020, at average annual rates of 1.7 percent; however, natural gas produces only half the carbon emissions of coal per unit of input. Average emissions from petroleum use are between those for coal and natural gas. The use of renewable fuels and nuclear generation, which emit little or no carbon, mitigates the growth of emissions.

Coal Accounts for Most U.S. Electricity-Related Carbon Emissions

Figure 121. Carbon emissions from electricity generation by fuel, 1990-2020 (million metric tons per year)



Electricity use is a major cause of carbon emissions. Although electricity produces no emissions at the point of use, its generation currently accounts for 36 percent of total carbon emissions, and that share is expected to increase to 38 percent in 2020. Coal, which accounts for about 52 percent of electricity generation in 2020 (excluding cogeneration), produces 81 percent of electricity-related carbon emissions (Figure 121). In 2020, natural gas accounts for 30 percent of electricity generation but only 18 percent of electricity-related carbon emissions.

Between 1997 and 2020, 50 gigawatts of nuclear capacity are expected to be retired, resulting in a 43-percent decline in nuclear generation. To compensate for the loss of nuclear capacity and meet rising demand, 345 gigawatts of new fossil-fueled capacity (excluding cogeneration) will be needed. Increased generation from fossil fuels will raise electricity-related carbon emissions by 213 million metric tons, or 40 percent, from 1997 levels. Generation from renewable technologies increases by 53 billion kilowatthours, or 12 percent, between 1997 and 2020 but is insufficient to offset the projected increase in generation from fossil fuels.

The projections include announced activities under the Climate Challenge program, such as fuel switching, repowering, life extension, and demand-side management, but they do not include offset activities, such as reforestation. Additional use of lower carbon fuels, reduced electricity demand growth, or improved technologies all could contribute to lower emissions than are projected here.

Sulfur Emissions Allowance Program Is Expected To Meet Its Goals

Figure 122. Sulfur dioxide emissions from electricity generation, 1990-2020 (million tons per year)

CAAA90 called for annual emissions of sulfur dioxide (SO_2) by electricity generators to be reduced to approximately 12 million short tons in 1996, 9.48 million tons between 2000 and 2009, and 8.95 million tons a year thereafter. More than 95 percent of the SO_2 produced by generators results from coal combustion, with the rest from residual oil.

In Phase 1, 261 generating units at 110 plants were issued tradable emissions allowances permitting SO_2 emissions to reach a fixed amount per year—generally less than the plant's historical emissions. Allowances may also be banked for use in future years. Switching to lower sulfur, subbituminous coal was the option chosen by more than half of the generators. In Phase 2, beginning in 2000, emissions constraints on Phase 1 plants will be tightened, and limits will be set for the remaining 2,500 boilers at 1,000 plants. With allowance banking, emissions are expected to decline from 11.9 million tons in 1995 to 11.4 million in 2000 (Figure 122). Since allowance prices are projected to increase after 2000, it is expected that 26.4 gigawatts of capacity—about 88 300-megawatt plants—will be retrofitted with scrubbers to meet the Phase 2 goal (Table 11).

Table 11. Scrubber retrofits and allowance costs, 2000-2020

Forecast	2000	2005	2010	2015	2020
Cumulative retrofits from 1997 (gigawatts of capacity)	13.6	13.6	25.8	26.4	26.4
Allowance costs (1997 dollars per ton SO_2)	90	240	293	182	130

New Legislation Will Reduce Nitrogen Oxide Emissions

Figure 123. Nitrogen oxide emissions from electricity generation, 1995-2020 (million tons per year)

Nitrogen oxide (NO_x) emissions in the United States will fall significantly over the next 5 years as new legislation takes effect (Figure 123). First will be the second phase of the NO_x reduction program from CAAA90, which calls for NO_x reductions at electric power plants in two phases—the first in 1995 and the second in 2000. It is expected that the second phase of CAAA90 will result in NO_x reductions of 1.5 million tons between 1999 and 2000.

A second piece of legislation, the ozone transport rule (OTR), will take effect in 2003. After studying the ozone transport problem, the U.S. Environmental Protection Agency (EPA) issued the OTR in September 1997. The OTR sets caps on NO_x emissions in each of 22 midwestern and eastern States during the 5-month summer season (May through September). The EPA wants to establish a cap and trade program with tradable emission permits. Holders of the permits would be free to use them themselves or sell them to someone whose NO_x emission reduction options are more costly.

The OTR is expected lead to a total NO_x emissions reduction of 0.7 million tons between 2002 and 2003 as control technologies are installed on utility boilers. By 2020, 10 gigawatts of capacity is expected to be retrofitted with advanced combustion controls, selective noncatalytic reduction units (SNCR) are expected to be added to 96 gigawatts, and selective catalytic reduction units (SCR) are expected to be added to 111 gigawatts. The annualized cost is estimated to be $2 billion, relative to about $200 billion in annual consumer expenditures for electricity.